BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2021-88-E

IN RE:	Dominion Energy South Carolina, Incorporated's 2021 Avoided Cost Proceeding Pursuant to S.C. Code Ann. Section 58-41-20(A)	))))	**POST-HEARING BRIEF OF THE SOUTH CAROLINA DEPARTMENT OF CONSUMER AFFAIRS**

Pursuant to S.C. Code Ann. Regs. § 103-851 and the briefing schedule established by the Public Service Commission of South Carolina ("Commission") in this proceeding, the Department of Consumer Affairs ("DCA" or "Department") submits this brief in lieu of a proposed order.

I. STATEMENT OF THE CASE

Dominion Energy South Carolina, Incorporated ("DESC" or "Company") requests approval of a standard offer, avoided cost methodologies, form contract power purchase agreements, and commitment to sell forms associated with the purchase of energy from interconnected qualifying facilities ("QFs"). The Company proposed to modify the existing Rate PR-1 based on updated calculations of avoided energy and avoided capacity costs. The Company additionally requests that the Commission approve a redesign of the existing PR-1 solar rate compensation based on four pricing periods (i.e., winter and summer on-peak and off-peak) to a single pricing period for all hours of delivery. Likewise, the Company requests that the Commission approve a proposed PR-1 *solar* rate that applies an avoided capacity rate to all hours of delivery. The Company proposes a PR-1 *non-solar* rate that provides compensation for generation provided during the hours of 6:00 to 9:00 a.m. during the months of December through February as recognition of contribution to the Company's peak system capacity requirements.

DESC also requests approval to modify the existing Standard Offer rate based on updated calculations of avoided energy and avoided capacity costs. The proposed Standard Offer for both solar and non-solar qualifying facilities ("QFs") is based on four pricing periods and would apply for the 10-year term for the years 2022-2026 and 2027-2031. Like DESC's proposal for PR-1 rates, compensation for avoided capacity for non-solar QFs is based on generation provided during the hours of 6:00 to 9:00 a.m. during the months of December through February, while compensation for solar QFs is a single rate applied to all hours of delivery.

Finally, DESC requests approval to increase the current interim Variable Interconnection Charge ("VIC") from $0.96 per MWh to $1.80 per MWh for Tranche 1 solar customers, and $3.43 per MWh for Tranche 2 solar customers. Tranche 1 Solar QFs are defined as solar resources who execute PPA with the Company after a baseline 340 MWs of interconnected solar capacity through a total of 973 MW of solar capacity, while Tranche 2 Solar QFs are defined as those Solar QFs who interconnect with the Company's system after the 973 MW threshold.

II. PROCEDURAL HISTORY AND EVIDENTIARY RECORD

On April 22, 2021, the Company filed its application pursuant to Commission Order No. 2021-166, S.C. Code Ann. § 58-41-20(A), and S.C. Code Ann. Regs. § 103-823. The Company subsequently filed two amendments to its initial application, the first on June 7, 2021, and the second on June 25, 2021. This second amendment included direct testimony from Company personnel supporting its proposal. On July 27, the Office of Regulatory Staff ("ORS"), the Carolinas Clean Energy Business Association ("CCEBA"), the Southern Alliance for Clean

Energy and South Carolina Coastal Conservation League ("SACE and CCL") each filed direct testimony. The Company filed rebuttal testimony on August 10, 2021, followed by other parties' surrebuttal testimonies on August 16, 2021.

The Commission held its evidentiary hearing in this matter August 18, 2021 through August 25, 2021. Subsequent to the conclusion of the evidentiary hearing, London Economics International LLC ("LEI") filed a report (hereafter, "LEI Report") with the Commission on September 16th, 2021. Pursuant to S.C. Code Ann. § 58-41-20(I), LEI was retained by the Commission as an independent expert to review the avoided cost methodologies of the Company.[1] Responsive testimony to the LEI Report was filed on October 8th, 2021, with a second evidentiary hearing addressing the LEI Report and responsive testimony on October 11th through 13, 2021.

The Department did not submit testimony in the matter, but thoroughly reviewed all pleadings, testimonies, and discovery responses, as well as the LEI Report. The Department also conducted cross-examination of party witnesses and LEI. Each of these documents and responses, along with information in the public domain, were considered in preparing the Department's recommendations.

III. FACTUAL AND LEGAL ARGUMENTS

A. SUMMARY

The Commission has received input from a variety of intervening parties, including those representing environmental concerns, solar facilities, and the general public, and has hired an outside expert to review the issues. DCA's interest in the current proceeding is that fair

[1] LEI was also retained by the Commission as an independent expert to review the avoided cost methodologies of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Docket Nos. 2021-89-E and 2021-90-E, filed concurrently with this docket.

compensation rates are established for QFs interconnected to DESC's system such that there is no subsidization by DESC's residential ratepayers. To accomplish this, the Commission should adopt the Company's proposed PR-1 and Standard Offer Rates, as modified below, finding that the proposal is in the best interest of QFs and Company ratepayers. The Commission should accept a technology neutral avoided cost structure, but reject the proposed seasonal allocations presented by SACE and CCL. The Commission should approve the Company's proposed avoided capacity cost and reject the application of a performance adjustment factor to the Company's proposed avoided energy costs. ORS's restriction on summer on-peak hours should be adopted and the Commission should initiate a study of the variable integration charge ("VIC"). Finally, the Commission should order specific filing requirements for future avoided cost filings.

B. STANDARD OF REVIEW

S.C. Code Ann. § 58-41-05, codified pursuant to Act No. 62 of 2019, directs the Commission to address renewable energy issues in a fair and balanced manner "both as a part of the utility's power system and as direct investments by customers for their own energy needs and renewable goals." Act No. 62 additionally requires the Commission adopt rates that ensure QFs are properly compensated for the energy they produce as required by the Public Utility Regulatory Policies Act of 1978 ("PURPA). (*See* S.C. Code Ann. §§ 58-41-05, -20(A)). PURPA requires electric utilities to establish non-discriminatory rates no greater than the utility's avoided cost of purchases. (18 CFR § 292.304 (a)(2)). Importantly, the Commission has recognized in previous Orders that electric utilities are entitled to recover from customers avoided costs paid to QFs under PURPA. (Order No. 81-214).

The statutory intent of PURPA and the state laws that implement it is to ensure that utility ratepayers do not subsidize QFs, while fairly compensating such generators at rates equal to the costs electric utilities incur for generation from its own system resources. (*see* April 22, 2021 Application at ¶31, referencing Joint Conference Comm. Report, H.R. Conf. Rep. No. 95-1750 at 98). Act No. 62 reinforces this prerogative by establishing that "[**a]ny decisions by the Commission shall be just and reasonable to the ratepayers of the electric utility...and shall strive to reduce the risks placed on the using and consuming public.**" (S.C. Code Ann. § 58-41-20(A), *emphasis added*)

C. ARGUMENT

1. The Commission should accept a technology neutral avoided cost structure.

DESC proposes separate PR-1 Rates for solar and non-solar QFs, as well as separate Standard Offer Rates for solar and non-solar QFs. These proposed rates not only have differing avoided capacity compensation elements but are structurally unique. In the case of both the proposed PR-1 Rates and Standard Offer Rates, the Company proposes a *non-solar* compensation based on a QF's system contribution during the period 6:00 a.m. to 9:00 a.m. during the winter months of December through February. Capacity contribution for *solar* QFs under the proposed PR-1 Rate and Standard Offer Rate are instead provided year-round based on kWh contribution.

The Commission should recognize that, while intermittent technologies may impose additional challenges on a utility's dispatch operations and need for reserves, the Company's avoided capacity cost is not dictated by a QF technology but is instead informed by system operations. As recommended by LEI, "a resource's capability to deliver capacity when required should determine its payment regardless of technology type." (Hearing Ex. 13, LEI Report p. 36; Tr. V8, p.124.5, ll.81-82). The use of a single avoided capacity rate that is technologically neutral would avoid the problematic occurrence of having different implied avoided costs for the same hour of service, and thus provide clear price signals and ensure QF compensation is appropriately assigned relative to utility system costs. (Hearing Ex. 13, LEI Report p.36)

The relevant portions of FERC regulations implementing PURPA require that rates for purchase from QFs be designed not to discriminate against qualifying cogeneration and small power production facilities (18 C.F.R. §292.304(a)(1)(ii)) and furthermore not exceed a utility's avoided costs. (18 C.F.R. §292.304(a)(2)). Ensuring fair compensation rates for QFs ensures these facilities are placed on an equal footing with electric utility-owned resources. This incentivizes electric utilities to not prioritize their own units that may be more expensive over potentially less expensive QF generation. In turn, this promotes a healthier, more diverse wholesale generation market. More important, the establishment of fair compensation rates incentivizes least-cost planning which benefits not only QFs, but also utility ratepayers.

SACE and CCL also argue that QF rates should be technology-neutral, (Sercy Direct, p.14, ll.6-11) but conflate this argument with one related to the appropriate seasonal allocation of avoided capacity rates. (Sercy Direct, p.29, ln.9 – p.30, ln.11). SACE and CCL recommend that the Commission allocate the Company capacity between winter morning hours and summer afternoon/evening hours at a rate of 52 and 48 percent, significantly increasing the contributions generators providing electricity to DESC during these summer afternoon and evening hours would receive.

Evidence in the proceeding shows that Company capacity needs are driven by system constraints in winter months. The Commission has approved for purposes of the Company's 2020 Integrated Resource Plan a plan designed to provide a minimum 21 percent winter reserve margin, higher than the 14 percent summer reserve margin. (Tr. V3, p.10, ll.6-25). Likewise, the Company has provided evidence that its marginal system costs are highest during early morning winter hours.

(Tr. V3, p. 9, ll. 3-20). This was confirmed by LEI which explicitly found that "as DESC notes, winter reserve margin requirements are [driving differentiation in the avoided cost change case." (Hearing Ex. 13, LEI Report p. 36)

SACE and CCL's proposed seasonal allocation would create negative impacts for DESC ratepayers. As previously noted, one intent of PURPA and Act No. 62 is to ensure that utility ratepayers do not subsidize QFs, while fairly compensating such generators at rates equal to the costs electric utilities incur for generation from its own system resources. SACE and CCL's proposal would lead to overcompensation for QFs that produce and sell electricity during afternoon summer hours, but have negligible operations during early winter morning hours prior or shortly after sunrise.

For the above reasons, the Commission should reject the proposed application of separate capacity rates for solar and non-solar QFs and instead, require all QFs be compensated for capacity based on the dispatchability of generation during the period 6:00 a.m. to 9:00 a.m. during the winter months December through February. The Commission should additionally reject the proposed seasonal allocations presented by SACE and CCL as being inconsistent with evidence in the record.

2. The Commission should accept the company's proposed avoided cost of capacity.

There has been significant discussion in this proceeding regarding the Company's calculation of its avoided cost of capacity. For example, ORS argues that the Company's analysis includes a mismatch of 100 MW capacity need being met with 66 MW generators. (Horii Direct, p.21, ll.16-20). SACE and CCL argue that the Company used unreasonably low estimates of costs when compared to data from the Energy Information Administration's report on Capital Cost and Performance Characteristics. (Sercy Direct, p. 20, ll.9-20). However, these discussions ignore the fact that market-based measures of avoided capacity deviate from those based on full replacement costs.

The core element of the Company's calculation of avoided capacity cost is derived from its calculation of the revenue requirement impact of the capital costs and fixed operating and maintenance ("FOM") expenses of an aeroderivative combustion turbine ("aero-CT"). (Hearing Ex. 13, LEI Report p. 29). This type of analysis is sometimes referred to as a Cost of New Entry ("CONE") analysis as it estimates the full replacement cost of new capacity in a system that is capacity constrained. (Tr. V7, p. 49, ll.13-17). There are, however, other various accepted approaches to evaluate avoided costs besides ones considering fixed costs associated with the construction of new power plants. (Hearing Ex. 13, LEI Report p. 9). The PURPA Title II Compliance Manual sponsored by the American Public Power Association ("APPA"), Edison Electric Institute ("EEI"), National Association of Regulatory Utility Commissioners ("NARUC"), and National Rural Electric Cooperative Association ("NRECA") identify the five different methods that are generally seen as effectively evaluating utility avoided costs. One of these methods includes auction-based market rates. (*Id.*)

A review of organized markets with capacity auctions demonstrates that the market value of capacity is often much lower than what an analysis of the fixed costs associated with the construction of a new power plant would show. The Base Residual Auction ("BRA") conducted by PJM Interconnection in the Mid-Atlantic, for example recently cleared for the 2022/2023 planning year at prices equal to 18.6 to 33.5 percent of the estimated CONE value of an aero-CT. (Hearing Ex. 14 and 15) Likewise, the Planning Resource Auction ("PRA") conducted by the Mid-Continent Independent System Operators ("MISO") recently cleared for 2021/2022 planning year at prices less than 2 percent of the estimated CONE value for new generation. (Hearing Ex. 16).

Capacity auction prices trade lower than the full replacement cost of capacity due to the presence of supply and demand. When an electric system has a surplus of generation capacity, the cost of new capacity reflects the costs of operating an additional unit during period demand periods rather than requiring the construction of a completely new generation unit assumed by analyses such as a CONE analysis. Indeed, the capacity price indicated by a CONE analysis is used in most organized electrical markets in the U.S. to represent a maximum price allowed in the market with the assumption being that, at this price, market participants will construct new generation capacity to alleviate shortage in the market.

Evidence provided in the record indicates that DESC anticipates maintaining significant operating capacity reserves through the next decade. The Company estimates that it will require operating reserve margins this winter and throughout the next ten years of no more than 632 MW.[2] (Corrected Exhibit PBD-2, p. 27). Historically, the Company has averaged at least 904 MW of available resources since July 2016. (Burgess Direct, p.15). With this reasonable level of capacity reserves, it is possible that the Company will not operate in a capacity shortage environment at any point in the near future.

The Commission should also recognize that adopted avoided costs in the current proceeding are expected to estimate the avoided costs to the Company in a forward-looking manner. (Tr. V7, p. 121, ln.23 to p.22, ln.8). On October 13, 2021, members of the Southeast Energy Exchange Market ("SEEM") announced that they had received clearance from FERC to

[2] Referenced reserve requirement assumes no more than 973 MW of solar capacity (Guidehouse Tranche 1 assumption) on DESC's system.

establish a new energy market platform covering the Southeast.[3] This new market will allow bilateral trading of power between members close to the time energy is consumed, utilizing available unreserved transmission. The Company, as well as fellow South Carolina utilities Duke Energy, Duke Energy Progress, and Santee Cooper, are expected to be founding members of SEEM.[4]

The creation of SEEM will allow for greater sharing of resources between utilities in the Southeast, expanding the diversity of resources across a wider geographic area. This increased diversity of resources is one of the reasons actual capacity clearing prices in organized markets trade substantively below the full CONE replacement price. (Tr. V7, p.56, ln.17 – p.57, ln.7). While SEEM represents only a starting point for a full integrated energy exchange market, (Tr. V7, p.58, ll.4-11) the Commission should recognize the potential for increased integration in the Southeast and the subsequent potential for decreased costs of avoided capacity for an individual utility like DESC.

The Company's proposed avoided cost of capacity represents a fair valuation of the economic value of avoided electric capacity additions on the Company's system. The proposed adjustments of ORS and SACE and CCL do not reflect that the economic value of capacity is typically substantively less than the full replacement cost of capacity and, if adopted, could lead to overcompensation and subsidization. For these reasons, the Commission should approve DESC's requested avoided cost of capacity based on $58.81 per kW-year.

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[3] *See*, https://southeastenergymarket.com/wp-content/uploads/NR-SEEM-FERC-Approval-2-2-vote-FINAL-101321.pdf

Also see the FERC notice, available at*:* https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20211013-3010&utm_campaign=press%2Fmedia%20outreach&utm_source=hs_email&utm_medium=email&_hsenc=p2anqtz--0ojzzmz1ulqzg9snm1d3td2rhaxkspbbs_5lxrqtharlcic5tlc5rfbix32v3rkuutnon

[4] *Id.*

3. The Commission should reject the proposed performance adjustment factor ("PAF") as not being supported by the evidentiary record.

SACE and CCL have suggested the Commission require the adoption of a Performance Adjustment Factor ("PAF") to calculations of avoided energy costs. (Sercy Direct, p.19, ll.2-3). SACE and CCL suggest that applying a PAF would place QFs on a fair and equal footing with utility-owned resources by allowing for a level of unavailability that is reasonably comparable to the level of unavailability of utility-owned resources. (Sercy Direct, p.18, ln.18 – p.19, ln.2). SACE and CCL did not calculate an appropriate measure of unavailability associated with DESC's generators, but did note that a PAF would typically be based on a measure of the annual forced outage rate of utility-owned generators. However, instead of suggesting the Commission use DESC specific data, SACE and CCL suggest the Commission approve a PAF of 1.05 based on Duke Energy 's 2019 avoided cost rate proposal. (Sercy Direct, p.19, ll.9-15).

LEI recommends DESC use a PAF developed from availability factors of its own fleet in subsequent proceedings. (LEI Report, p. 35). However, LEI also recommends that, in the absence of such information, SACE and CCL's proposed PAF of 1.05 be adopted. (*Id.*) Like SACE and CCL, LEI's recommendation for a PAF of 1.05 is not supported by an examination of resources on DESC's system, nor on an examination of the availability of QFs selling electricity to DESC. (Tr. V7, p.59, ln.19 – p.60, ln.5)

The Commission should reject any proposed adjustment to the Company's avoided capacity cost estimates for generator unavailability that is not grounded on an examination of the Company's generators. The question before the Commission in the current proceeding deals with the appropriate determination of avoided costs for DESC, and not Duke Energy. The two utility systems have different resources supporting them, and therefore it is not unreasonable to believe that an examination of annual forced outage rates for DESC-owned generators would be less than the 5 percent utilized in Duke Energy avoided cost calculations. (Tr. V7, p.63, ll.19-24).

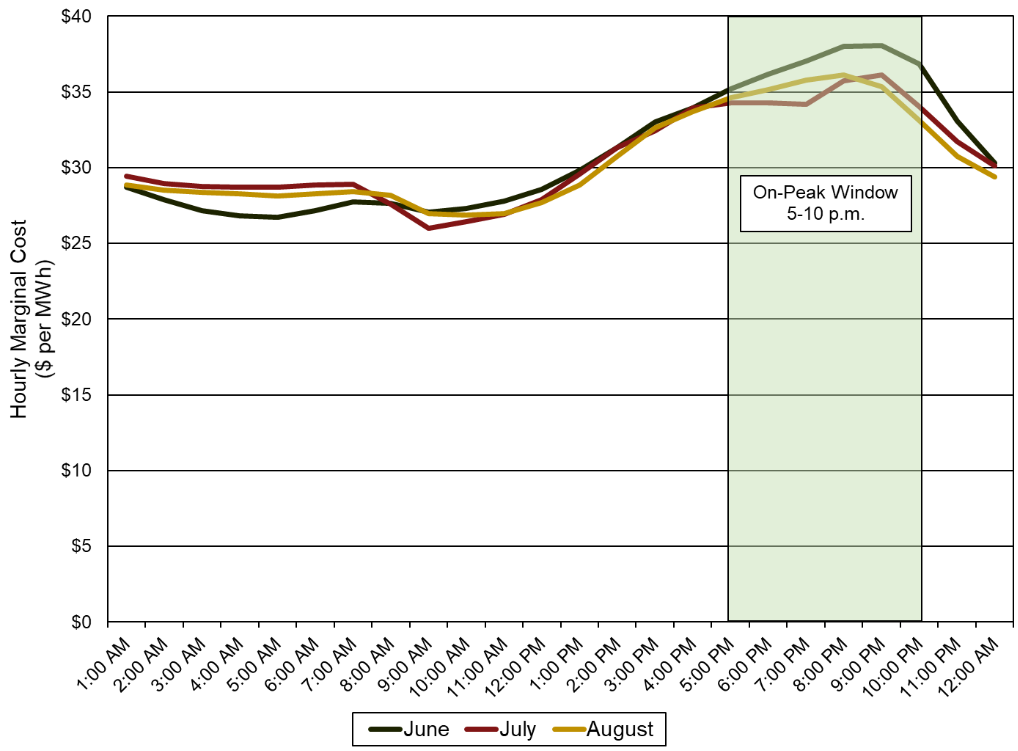
Arbitrarily assigning an upward adjustment to the avoided capacity cost calculations of DESC could result in an inappropriately high compensation rate for QFs for capacity provided to the DESC system. This would result in DESC ratepayers inappropriately subsidizing QFs for this capacity, in direct contradiction to S.C. Code Ann. § 58-41-05 and PURPA. The Commission should defer applying any PAF until it has DESC-specific information to judge the acceptability of any proposed factor.

4. The Commission should adopt ORS's recommended restriction on summer on-peak hours.

In the current proceeding, ORS proposes that DESC decrease the summer on-peak period for its non-solar PR-1 rate from DESC's proposed 11:00 a.m. to 11:00 p.m. window to 2:00 p.m. to 11:00 p.m. ORS finds that DESC estimates an average 2022 summer marginal cost for 11:00 a.m. through 2:00 p.m. that is significantly lower than the average costs for the other peak hours, and thus should not be included in the summer on-peak rate. (Horii Direct, p.13, ll.11-13)

Evidence provided in the current proceeding demonstrates that DESC's avoided cost of energy are driven by high marginal costs in early morning winter hours and late evening summer hours. (Horii Direct, p.13 and Direct Exhibit KS-3). Figure 1 below is a line graph depiction of the summer month marginal costs "heat map" provided by DESC's discovery responses and submitted as Sercy Direct Exhibit KS-3. As demonstrated in the figure, hourly marginal costs are estimated to peak during all summer months in the period 7:00 p.m. to 9:00 p.m., with noticeable increased marginal costs for the period 5:00 p.m. to 7:00 p.m. and 9:00 p.m. to 10:00 p.m.

Figure 1: Summer 2022 Estimated Hourly Marginal Costs



Time-variant energy credits provide price signals to generators to provide electricity when most valuable. A more focused on-peak period provides even greater incentives for generators to provide power when it is most valuable to DESC and its retail customers. (Horii Direct, p.13, ll.7-10). This is particularly important when considering non-dispatchable, intermittent resources such as solar QFs which generate electricity at higher levels during early afternoon hours coincident with high solar angles. Compensating these solar QFs for generation during these hours at the same on-peak rates as generation during the early evening hours during peak marginal costs leads to these customers being overcompensated for their generation sold to DESC. This is counter to the statutory intents of PURPA and Act No. 62 that utility ratepayers do not subsidize QFs. (*see* Application at ¶31, referencing Joint Conference Comm. Report, H.R. Conf. Rep. No. 95-1750 at 98; and S.C. Code Ann. § 58-41-20(A)).

For these reasons, the Commission should accept ORS's proposed restriction on summer on-peak hours, eliminating the period 11:00 a.m. to 2:00 p.m. from on-peak. The Commission should likewise consider adopting a more restrictive summer on-peak period than proposed by ORS, such as 5:00 p.m. to 10:00 p.m. to enhance the hourly price incentive for generators to provide power during this elevated cost period.

5. The Commission should reject proposals to change the VIC and direct future analysis to investigate the ongoing system costs associated with the interconnection of variable generation units.

In the current proceeding, the Company requests to change its interim VIC of $0.96 per MWh for all Solar QFs to $1.80 per MWh for "Tranche 1" Solar QFs and $3.43 per MWh for "Tranche 2" Solar QFs. Tranche 1 Solar QFs are defined as solar resources who execute PPAs with the Company after a baseline 340 MWs of interconnected solar capacity through a total of 973 MW of solar capacity. Tranche 2 Solar QFs are defined as those Solar QFs who interconnect with the Company's system after the 973 MW threshold.

DCA does not believe the Commission should accept DESC's proposed increase of the current interim VIC due to methodological issues raised in the current proceeding. For example, CCEBA argues that Guidehouse inappropriately utilized simulation modeling of future operation conditions rather than actual historical integration costs. Likewise, CCEBA argues that Guidehouse did not weight the modeled integration costs of hourly solar by hourly solar generation, thus potentially inflating costs during periods of expected low solar production. Finally, CCEBA argues that the analysis unfairly assigns 100 percent of integration costs associated with baseline solar facilities (i.e. those included in the initial 340 MWs) to Tranche 1 and furthermore makes arbitrary restrictions regarding the potential operations of the Fairfield pumped hydro facility during specific hours, increasing the Company's need for generation reserves.

The LEI Report shares many of CCEBA's concerns, noting that "the extent of contrary evidence introduced regarding the VIC analysis supports the need for a truly independent study." (LEI Report, p. 54). The LEI Report finds the best approach would be to continue at the current interim VIC until the results of a comprehensive independent study are available; however, LEI would concur that a VIC for Tranche 1 of $1.80 per MWh may be reasonable for newly contracted resources over the next two years if the Commission believes that it must set a fixed VIC as part of this proceeding. (LEI Report, p. 56).

The Company's Amended Application notes that the Commission is directed by S.C. Code Ann. § 58-37-60 to conduct an integration study using its own consultant in a separate docketed proceeding. (Amended Application, p. 9). This integration study proceeding was opened by the Commission in Docket No. 2020-219-A, and remains ongoing. For this reason, ORS argues that it is premature to adopt new VIC values at this time without an independent analysis from the Commission's consultant in Docket No. 2020-219-A. (Horii Direct, p.10, ll.12-15).

Importantly, all parties in the current proceeding believe that the interconnection of intermittent resources may impart some costs to the electrical transmission system. At issue is how much of a VIC should be applied to account for this increased cost and when. Mr. Horii, for example, notes he has conducted extensive work in markets with large penetration of intermittent solar and wind resources and has found that these resources typically require additional ramping capability and reserves to meet both the intermittent nature of these resources and the diurnal ramping characteristics of solar generation in particular. (Horii Direct, p.7, ll.:3-7). These additional system requirements lead to additional costs associated with start-up costs, fuel costs, and O&M expenses resulting from resources operating at levels below their maximum efficiency to accommodate the intermittent generation capacity. (*Id* at ll.7-11)

CCEBA witness Burgess admits that there may have been limited costs associated with the integration of solar systems in the recent past and that this cost may become more noticeable at higher levels of solar penetration:

> I think the Commission should consider the possibility that incremental costs for DESC to integrate solar in the recent past and near future are **close** to zero, and that the VIC should similarly be set at $0/MWh. **There may be incremental integration costs that should be contemplated under even higher penetrations of solar.** However, a VIC charge of any level for solar Tranches 1, 2, and 3 may be premature. (Burgess Direct, p.16, emphasis added)

With the current disagreements regarding the Company's proposed analytical support for increasing the VIC, the Commission should refrain from changing the interim VIC at the current juncture. However, the Commission should seek to provide an independent study consistent with S.C. Code Ann. § 58-37-60. During the hearing ORS noted such a study would require a minimum of six months to complete after the hiring of an independent consultant. (Tr. V6, p.96, ln.23 – p.97, ln.6). LEI agreed with this timeline. (Hearing Ex. 13, LEI Report p.55).

6. The Commission should adopt meaningful filing requirements for future avoided cost filings to avoid transparency concerns.

SACE and CCL argue that the Company's avoided cost filing does not meet the required level of transparency to allow for underlying assumptions, data, and results to be independently reviewed and verified. (Sercy Direct p.33, ll.3-9). Specifically, SACE and CCL argue that the Company omitted discussion of "several inputs, assumptions, and methodologies the Company used to develop its proposal." (*Id.* at ll.8-9). These include information on inputs such as natural gas prices and load forecasts. (*Id.* at ll.9-11). SACE and CCL additionally criticized the lack of clarity from DESC regarding expansion plans utilized in its production cost modeling simulations. (*Id.* at p.34, ll.7-10).

DCA believes there is sufficient evidence in the record for the Commission to make a determination on the merits of the Company's proposed update to avoided costs. Additionally, ORS's consultant directly addressed questions of transparency by noting that information provided by the Company allowed for the assessment of the reasonableness of the proposal, including sufficient access that allowed for ORS manipulation to improve the Company's calculations. (Horii Direct p.4, ll.19-22)

The evidentiary record was also sufficiently transparent to allow LEI to prepare and file an 81 page report assessing the filing. LEI also addressed issues of transparency in its filed report, finding the Company to be responsive to interrogatories in a timely manner. (Hearing Ex. 13, LEI Report p.70). LEI did criticize the Company's lack of a detailed presentation of modeling and scenario assumptions, and noted how details regarding the Company's loss of load calculations were presented as unfiltered output from a statistical program package. (*Id.*) However, LEI did not argue in its report that the Company's filing lacked appropriate transparency, but merely that some of the application was presented in a manner that increased the need for interrogatories. (*Id.*)

While the Commission should recognize that the evidentiary record was eventually sufficiently established for it to render a determination, for a notable period in this proceeding this was not the case. The Company's initial application was filed on April 22, 2021 in an incomplete manner that prevented substantial review. DCA filed, and the Commission granted, a motion to review the sufficiency of the Company's application. This resulted in the Company filing an amended application on June 7, 2021. Without this additional information, other parties would have been left in the dark regarding important aspects of the Company's application until it filed its testimony on June 29, 2021, just two weeks prior to the required filing date for intervenor testimony.

As iterated in its closing arguments, DCA believes strongly that the Commission should require complete, substantive filings for all applications. (Tr. V9, p.8, ll.7-10). DCA further believes that utilities should be required to submit direct testimony and supporting evidentiary documentation simultaneously with an application in order to allow parties and the Commission the opportunity to thoroughly review the information as efficiently as possible. (Tr. V9, p.8, ll.10-15).

Due to the complex nature of these proceedings, the Commission should adopt meaningful minimum filing requirement standards for the Company prior to its next avoided cost application. These standards should require the full filing of methodological support along with the application to ensure full disclosure and adequate time for review. Consistent with the recommendation of SACE and CCL in the current proceeding, (Sercy Direct, p.34, ln.15 – p.35, ln.4) the Commission should specifically require the Company file the information below:

- All production cost modeling inputs and outputs, including fuel prices, variable O&M, generating unit operating parameters, load forecasts, hourly avoided cost outputs, and system dispatch data;
- Quantitative analysis and methodologies, with all inputs and outputs, for designating pricing periods;
- Resource expansion plans assumed for both avoided energy and avoided capacity calculations;
- Resource adequacy analyses, with all data inputs and outputs, used to develop avoided capacity rates;
- All workpapers used to calculate avoided energy and capacity rates from underlying production cost and capital cost modeling.

IV. CONCLUSION

The Commission should accept the Company's proposed PR-1 and Standard Offer Rates with the Department's recommended modifications, as set forth in this brief, because they are consistent with the intent of PURPA and the state laws that implement it, supported by the record, and in the interest of South Carolina consumers.

Respectfully submitted,

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